COPRODUCTION OF METHANOL AND SNG FROM COAL: A ROUTE TO CLEAN PRODUCTS FROM COAL USING "READY NOW" TECHNOLOGY

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INTRODUCTION

Clean fuels and chemicals have been produced from coal for more than a century. When natural gas and crude oil became readily available at low cost, coal use decreased. In most of the developed countries, only limited research and development efforts continued. However, where gas and oil were not readily available and coal was, the development has continued, and today we have three primary processes to convert coal into a synthesis gas which can be cleaned up to remove sulphur and other objectional impurities and which can be used as a fuel as is, upgraded to a pipeline quality or high Btu gas or converted into other products (liquid fuels or chemicals). The main processes in use today on a commercial scale are the Winkler, the Koppers Totzek, and the LURGI process. These processes are competitive, and the choice for any particular application is made on both the quality and characteristics of the coal available and on the products desired.

Many other processes are in various stages of development--bench scale, pilot plant, and demonstration plant--but none are in full scale commercial operation, nor have any of them been selected for full commercial scale plants that have been announced. I am excluding all of these from "ready now" technology on the basis that no companies or investors have selected any of the new processes for major new plant investments. Of those plants announced for construction in the United States, the majority have selected the LURGI process. These plants are designed to produce high Btu gas essentially equivalent to natural gas for augmenting the diminishing supplies of natural gas being produced in the United States.

The Winkler and Koppers Totzek processes produce a gas from coal consisting essentially of carbon monoxide and hydrogen as worthwhile and usable constituents. These processes minimize the production of by-products such as tars, phenols, naptha, etc.

The LURGI process, which operates at substantially higher pressures, produces in addition to the carbon monoxide and hydrogen, a substantial amount of methane and also substantial quantities of ammonia, naptha, phenol, and tars. The amount of methane, depending on the type of coal being used, can be as high as 33% of the methane, CO and hydrogen produced.

The writer and his associates were working on and trying to develop an economic production facility for SNG from a specific Western coal. We had decided that the LURGI technology was the best for our particular conditions, coal feed and desired product. The particular coal that we were using resulted in a 1-1-2 mol ratio of methane, CO and hydrogen. We were intrigued by the CO-hydrogen ratio which is stoichiometrically what is required to produce methanol, and we therefore decided to evaluate a project which would make methanol out of the carbon monoxide and hydrogen and save the methane for our original purpose, and that is, the production of SNG for addition to the U. S. natural gas supply.

The equipment, processing steps, etc. for cleaning up the synthesis gas produced from coal proved to be essentially the same, whether we converted the gas to SNG via a methanation step or whether we converted it to methanol using existing technology. We therefore developed capital and operating cost figures for a coproduct plant producing SNG and methanol for comparison with our already completed SNG from coal plant. We elected not to make a third study, and that is the production of methanol, only, from the synthesis gas produced from the coal, but studies on this subject have been made by others, and one of the papers in this session covers such a study. The reason we did not conduct the third study was because we felt that the much lower thermal efficiency going from coal to methanol would not be anywhere near as economically attractive as the coproduct plant or the straight SNG plant. The lower Btu efficiency of a methanol from coal plant, between 45 and 50%, are confirmed by Dr. Dennis Eastland of Davy Powergas in his paper at this session.

We believe that our evaluation shows that there are some substantial advantages for the coproduction of SNG and methanol and that a very large advantage exists if the methanol can be sold at a premium price above fuel value as it historically has sold and currently sells as a chemical, rather than a fuel.

This report will describe the similarities and differences between a plant to produce SNG and a plant to produce methanol and SNG.

* * * * * *

TECHNOLOGY

Exhibits 1 through 7 summarize technology, capital and operating cost of a coal derived coproduct SNG/methyl fuel project compared to a coal derived SNG project alone.

It should be pointed out at the outset that these studies do not include capital or operating costs of developing a mine.

Exhibit No. 1, an abbreviated block flow diagram, depicts a simplified flow configuration on a LURGI technology based coal gasification project. This is a typical configuration and is almost identical with that in the Wesco coal gasification filing and with much fundamental similarity in the El Paso gasification schemes as submitted to the Federal Power Commission (although there are some differences). The point to be made here is that all process steps are commercially proven.

Output in this case is a standard 250 M^2SCFD of SNG at 987 HHV with an input of 30,079 ST/D of Buffalo, Wyoming, coal, which is the basis of a study conducted for Transco by Fluor. There are some 8,100 BPD of liquid fuel by-products as fuel oil, naptha and tars. 150 ST/D sulphur is produced, 180 T/D ammonia and 114 T/D phenols.

Exhibit No. 2 shows a block flow diagram of how this existing study configuration would be modified for coproduction of SNG and methanol. It is to be remembered that the whole coal gasification process would still be based essentially on LURGI coal gasification technology.

In this exhibit, the red cross hatching indicates identical battery limits units (inside the gasification complex) compared to SNG only. The green indicates units and systems that would change in size--more or less. The blue cross hatching would be units that are net additions needed to realize the fuel coproducts.

The methanol synthesis technology for this report has been evaluated from information received from Imperial Chemical Industries, Ltd. (ICI), who are licensors of a methanol process. ICI has reviewed the Transco concept for the methanol yield data.

Gross coal input for the coproduct mode is 33,185 ST/D, some 10% more than the straight SNG mode. The quantity of gasification feedstock would remain the same for either mode, but the increased quantity of coal in the coproduct mode is required for the increased steam and power requirements.

All other by-products such as the liquid fuels, sulphur, ammonia and phenols, would be produced in exactly the same quantity as in the SNG alone mode.

Exhibit No. 3 makes a three-way thermal efficiency comparison between the two modes. The first compare Btu's produced per day in prime fuels only. In this case, the co-product mode produces 4.33% more than SNG alone. (Of the total co-product, 59% is SNG and 41% is methanol).

In the second comparison, the thermal efficiency of total fuel and process coal feed (no by-products) is considered. Here, the SNG single product has an advantage of about 2.8%.

In the third comparison, the total products (except sulfur and ammonia) are considered. This results in a greater differential (3.79%) in favor of SNG alone.

CAPITAL AND OPERATING COSTS

Exhibit No. 4 shows conceptual capital cost comparisons between the two modes in the general category of process units, utility and offsite units. Basis of the cost data is the Fluor report, in turn, derived from the Wesco work. Costs are taken as 1974 basis. It can be seen that the dollar changes between the modes are minimal with the greatest effect in the addition of the methanol synthesis loop and purification. Net dollar addition is $25,118 M for the co-product mode.

In the utility units, a large change is the elimination of the compression step in SNG but the addition of more steam generating and water related facilities. Net dollar addition is $15,026 M.

The offsite costs are virtually the same with the exception of tankage and this has been increased in the co-product mode to provide two weeks' inventory of methanol fuel. Dollar differential is $3,002 M.

Exhibit No. 5 summarizes capital cost of both modes in the three general categories, and shows the effects of such additives as sales tax, initial charge of catalysts and chemicals, fees and royalties, railroad spur, environmental, spare parts, water supply, working capital, interest during construction and contingency. Net dollar differential after final addition is $59,679 M.

Exhibit No. 6 on the operating cost estimate shows the comparative cost for the first full year of operation, 1974 basis. This example shows the effect of total coal feed at 30¢/M^{2}Btu with the addition of catalyst and chemicals, wages, overheads, maintenance supplies, ash disposal, taxes and insurance and water supply. Credits are given in this line-up for the values of the by-products which, as can be seen, are the same either case.

As a matter of interest, the operating cost reflects an organizational roster of 620 people for SNG alone versus 650 people in co-product.

It should be remembered that these studies exclude mine operating and development costs and that these are covered by the purchase price of the coal. The subsequent economic studies reflect the capital costs, operating cost and the effects of varying the coal costs.

The question has been raised as to the effects of reducing the co-product facility size to reduce capital dollar requirement. For this purpose, a facility to produce an arbitrary 2,000 ST/D product methanol with corresponding 56.67 M^{2}scfd of SNG output has been cost evaluated. The seventh exhibit shows a resulting capital cost-size plot. In general, reducing the production size from the prime study point by 63% cuts capital cost about 50%. The corresponding coal requirement reduces from 33,200 ST/D to 12,200 ST/D. Subsequent discussions on economics will show the effects of size reduction on product value.

ECONOMICS

The economic analysis which is presented looks at the co-production of methanol and SNG on two bases, one which assigns the same value to a Btu regardless of the product form and the other which recognizes the real world historical pricing relationship between the cost of clean liquid fuels and natural gas. Clean liquid fuels have historically sold at a substantial premium over natural gas. Currently, this premium is about \$1 per million Btu. Chemical methanol, which can be produced for a negligible additional cost, has sold at a substantial premium above clean liquid fuels on a contained Btu basis.

The economics show that if a clean liquid fuel or a chemical methanol market price can be obtained, the co-product plant can produce a greater return on capital investment and requires less capital investment per dollar of annual sales, or a lower sales price for the SNG.

Exhibit No. 8 shows that on a combined total Btu basis, SNG alone appears the more attractive venture. SNG/methanol co-production requires a product price of about 8% more per million Btu and costs \$60 MM more to build.

Exhibit No. 9 shows what the minimum required SNG price would be at different methanol prices to give a 20% return on equity. As an illustration, select a point which is near today's open market prices: coal at 90¢/MMBtu and gas at \$1.48/MMBtu. Minimum required methanol price would be \$6.00/MMBtu or 38.9¢/gal. Current price of methanol is 32¢/gal.

Exhibit No. 10 shows the same information in graphic form.

For the reduced size plant discussed in the technology section, we have also calculated the average required sales price for the products based on Btu content as shown below:

Coal Price - ¢/MMBtu	Required Sales Price - $/MMBtu Methanol Rate, ST/D 5420	2000
30	2.12	2.44
60	2.73	3.05
90	3.34	3.66
SNG Rate - MMSCF/D	154	57

ECONOMICS - BASES AND ASSUMPTIONS

1. 20% DCF internal rate of return on equity.
2. Financing provided on a 70/30 debt/equity ratio.
3. Interest rate of 9% per year on all debt, both construction and long-term.
4. Book depreciation done on straight line basis.
5. Tax depreciation done on double declining balance with normalization basis.
6. Sinking fund payments 5% per year on a semi-annual basis.
7. Five-year construction period and 25-year operation period.
8. Startup 1 January 1974.
9. Operating and maintenance costs constant for 25-year plant life.
10. Coal feed assumed to be available at plant inlet at a given purchase cost.
11. For combined total in Exhibit No. 8, Btu prices were apportioned into the expected split of 59% SNG and 41% methanol.

METHANOL MARKET - FUEL

Gasoline substitute is the greatest potential market for fuel grade methanol. It is so great that the largest conceivable plant would supply less than 3% of the market. However, the introductory problems to this market are almost insurmountable for the near future, except for possibly a captive fleet (i.e., New York City taxis).

The market that would be served first appears to be peaking turbine fuel. This is the conclusion of government agencies, supported by G. E. and Westinghouse confirmation that methanol has 7% higher efficiency and 6% more KW than fuels being used at present.

Exhibit No. 12 shows some statistics looking at specific areas and markets. Electric utility boilers not requiring conversion (gas burning) in Texas and Louisiana alone would consume 5,900 tons/day of methanol. Boilers requiring conversion (oil burning) in the same area would require 177,000 tons/day. And gas turbines would require 2,260 tons/day.

Our two large customers would consume a combined total of about 5,500 tons/day in their gas turbines. In yet another use, Transco compressors to transport one trillion CF/year would require 6,300 tons/day.

Exhibit No. 13 shows the total U. S. peaking fuel requirement for electric utility gas turbines and internal combustion engines. The daily requirement of methanol would be 32,000 tons for gas-burning turbines and 62,800 tons for oil-burning turbines.

The 1974 electric utility consumption of all fuels for gas turbines used to generate electricity is equivalent to more than 100,000 tons per day of methanol. Methanol has a 7% thermal efficiency advantage over the fuels that are currently being used (natural gas, LPG's, #1 and #2 fuel oil and JP). The increased thermal efficiency results from the higher mass flow through the turbine (approximately 2%) and from the use of vaporized methanol (approximately 5%). Liquid methanol boils at 64.65° C. and can be vaporized with waste heat from exhaust gas that is at too low a temperature for any other economic use. Methanol's advantages over these conventional fuels for this use should price it at a modest premium versus these fuels.

Another type of guarantee that will be necessary for a coal/methanol/SNG project will be some form of downside market price guarantee which we presume can only be furnished by the U. S. government. The joint methanol fuel report prepared by a group of governmental agencies and bureaucracies has recognized that such guarantees will be necessary for such a project to become a reality. This government report also recognizes the need for a substantial decrease in the time required for obtaining all of the government-required approvals.

METHANOL MARKET - CHEMICAL

The current United States production of methanol is approximately 12,500 short tons per day. The existing chemical use market is growing at approximately 10% per year. The current supply-demand imbalance amounts to a shortage in excess of 1,000 tons per day. No new plants are under construction. Only one plant is being designed (Celanese's Bishop, Texas plant; estimated additional production capacity: 1,500 tons per day). Exhibit No. 14 shows a profile of the chemical methanol market.

Essentially, all chemical methanol produced in the U. S. today is made from natural gas. The natural gas consumption by these plants is approximately 500 MMCF per day.

The posted selling price for methanol at the end of the third quarter of '74 was 32¢ per gallon ($5/MMBtu) FOB producing plant, but none was available at this price. The drastic downturn in the home building and automotive market (which account for over one-half of all methanol consumption) has created a surplus of supply over demand. Short of a long term recession, additional chemical production will be needed at near its historical growth rate.

The future cost of chemical methanol calculated on a Btu value cannot be less than the cost of 1.8 Btu of purchased natural gas plus $1.00 per million Btu of methanol produced. For example, if natural gas is $2.00 per million Btu, the cost of methanol would be $3.60 for natural gas plus $1.00 for plant cost for a total of $4.60 per million Btu. Most U. S. methanol is produced from intrastate gas for which sales have been reported as high as $2.05 per MMBtu in 1975.

For these reasons, we believe that methanol sold in the chemical marketplace will continue to command its historic premium price over the cost of clean liquid fuels. We believe that this premium will amount to a minimum of $1.00 per MMBtu. On this basis, chemical methanol price can be expected to at least maintain its current price. We believe that the current price of clean liquid fuels is between $2.00 and $2.50 per million Btu.

Therefore, to the extent that methanol can be sold in the chemical market, this will represent the highest price which can be obtained.

Because of the domestic shortage of natural gas, even in the intrastate market, the chemical producers with whom we have had conversations believe that chemical methanol will be produced from coal in the United States in the 1980's.

CONCLUSIONS

On the concept grade evaluation that has been made, we conclude that further in-depth effort should be made:

1. To produce feasibility grade capital and operating cost and product cost,
2. To evaluate marketing potential for the products (SNG and methanol), and
3. To obtain governmental encouragement and support for such a venture by the private venture or free enterprises energy production interests.

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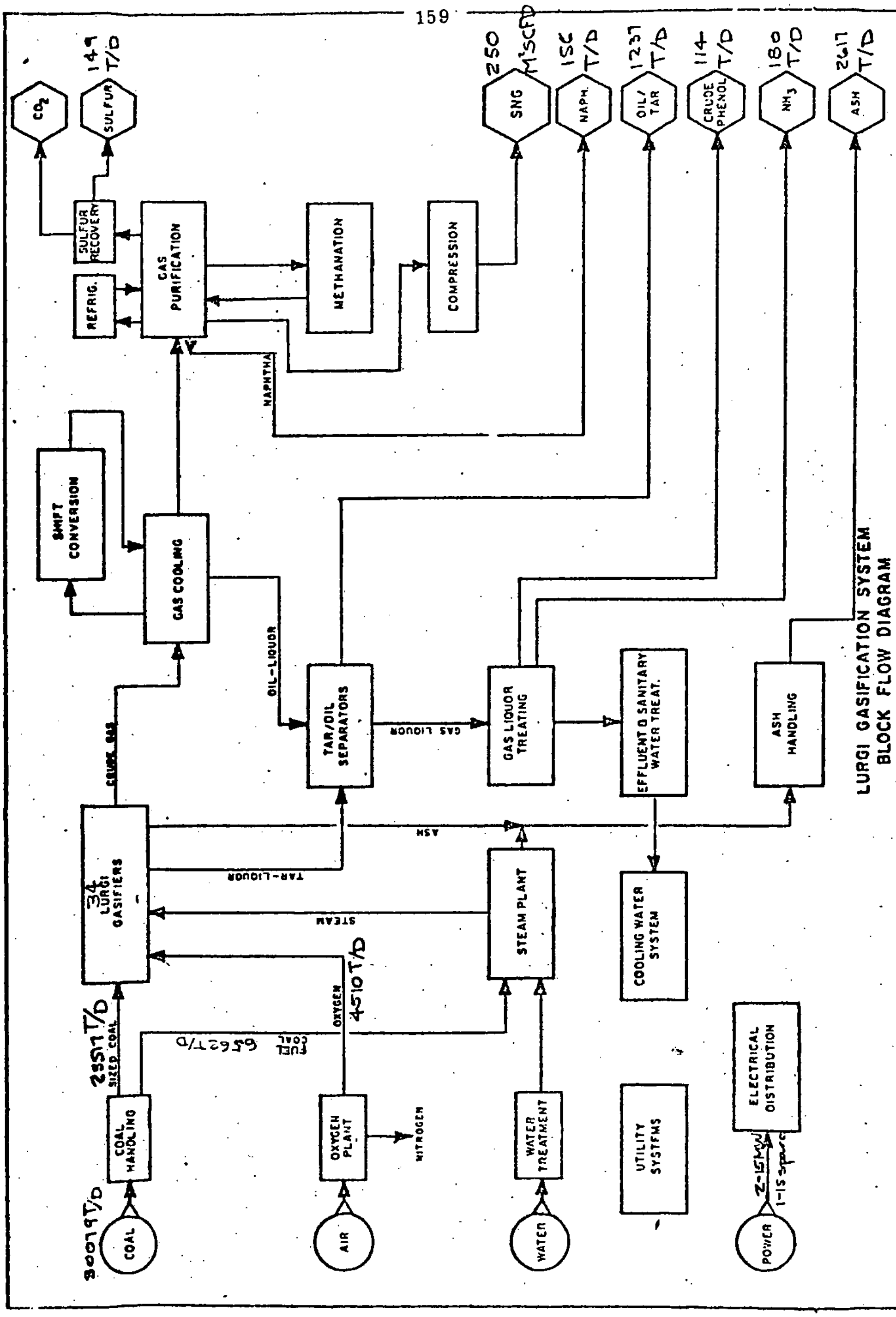
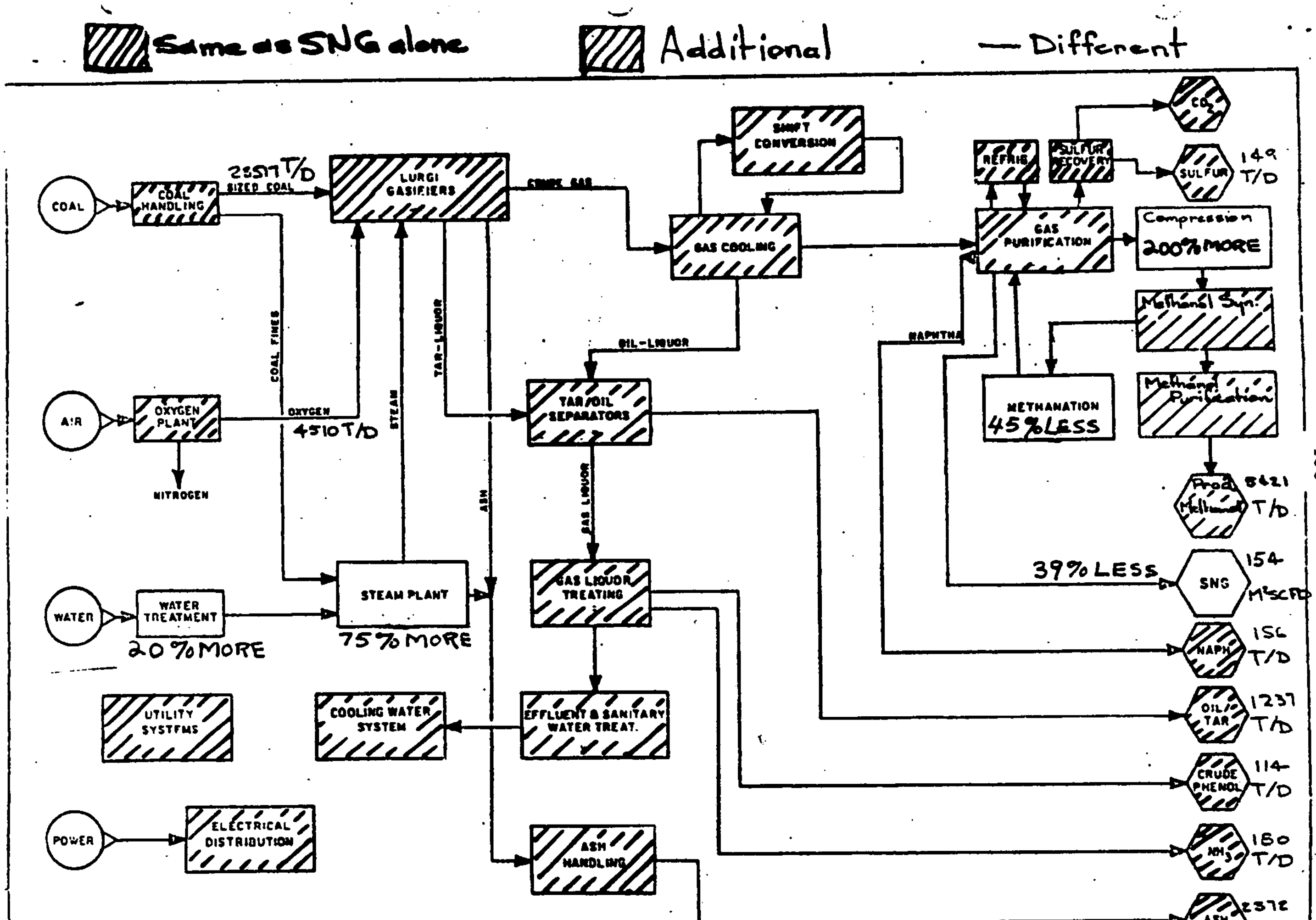
Exhibit 1



LURGI GASIFICATION SYSTEM
BLOCK FLOW DIAGRAM

SNG Alone



LURGI GASIFICATION SYSTEM
BLOCK FLOW DIAGRAM

Co-Product-Methanol/SNG

EFFICIENCY COMPARISONS
SNG VS SNG/MeOH FROM COAL

I. PRIME END PRODUCTS ONLY

SNG/MeOH:

SNG - 153.611 M^2scfD @ 987 Btu/scf = 151.614 M^3BtuD
MeOH - 5420.8 T/D @ 9760 Btu/lb = 105.814 M^3BtuD
257.428 M^3BtuD

SNG ALONE:

SNG - 250 M^2scfD @ 987 Btu/scf = 246.750 M^3BtuD

COMPARISON:

Difference = 257.428 - 246.750 = 10.678 M^3BtuD Benefit from Co-Product
Or = 4.327% increase over SNG alone.

II. PRIME END PRODUCTS VS FUEL INPUT

SNG/MeOH:

Feed coal of 23517 T/D @ 7618 Btu/lb = 358.305 M^3Btu
Fuel; boiler, power, SH. - 9668 T/D @ 7320 Btu/lb = 141.540 M^3Btu
499.845 M^3Btu

Produces - 257.428 M^3BtuD; Efficiency = 51.50%

SNG ALONE:

Feed coal of 23517 T/D @ 7618 Btu/lb = 358.305 M^3BtuD
Fuel; boiler, power, SH. - 6562 T/D @ 7320 = 96.068 M^3BtuD
454.373 M^3BtuD

Produces - 246.750 M^3BtuD; Efficiency = 54.31%

III. ALL END PRODUCTS VS FUEL INPUT

SNG/MeOH:

Feed & Fuel = 499.845 M^3BtuD
Products: 257.428 + 49.428 = 306.856 M^3BtuD

Efficiency = 61.39%

SNG ONLY:

Feed & Fuel = 454.373 M^3BtuD
Products: 246.750 + 49.428 = 296.178 M^3BtuD

Efficiency = 65.184%

CONCEPTUAL CAPITAL COST SUMMARY

(1974 Costs)

	SNG ONLY 250 M^2scfD	SNG/MeOH 153.61 M^2scfD/5421 st/D
Process Units	$ 186,631 M	$ 211,749 M
Utility Units	115,815	130,841
Offsites	57,829	60,831
SUBTOTAL	$ 360,275 M	$ 403,421 M
Sales Tax @ 1.155%	$ 4,161 M	$ 4,660 M
Initial Charge - Catalyst & Chemical	2,650	5,210
Fees, Royalties & Eng.	5,200	5,200
Fees, Royalties & Eng.	---	1,500
Railroad Spur	4,700	4,700
Environmental	1,000	1,000
Spare Parts	1,801	2,017
Water Supply	12,000	13,500
SUBTOTAL	$ 391,787 M	$ 441,208 M
Working Capital	10,772	14,920
Interest During Construction	61,979	63,147
Contingency	39,179	44,121
TOTAL	$ 503,717 M	$ 563,396 M

DOES NOT INCLUDE:
1. Construction camp
2. Product SNG pipe lines (nor $ difference for size differences)
3. Loadout and handling for MeOH
4. Escalation
5. Startup Costs
6. Land
7. Mine & support facilities

CONCEPTUAL COST EVALUATION
(1974 Costs)

SNG FROM COAL VS SNG/METHANOL FROM COAL
(BASIS: FLUOR FEASIBILITY STUDY)

PROCESS UNITS	SNG ONLY	SNG/MeOH
Gas Production (Lurgi)	$ 65,533 M	$ 65,533 M
Shift Conversion	10,061	9,000
Gas Cooling	8,739	8,739
Rectisol (Gas Purification)	66,783	65,783
Methanation	22,021	12,100
Phenosolvan (Ammonia - Phenol separation)	13,494	13,494
Methanol Loop	---	37,100
Ethylene Conversion	---	---
TOTAL	$186,631 M	$211,749 M
UTILITY UNITS		
H_2 Compression	$ 5,370	$ ---
Uxygen Plant	36,282	36,282
Sulfur Recovery	4,693	4,693
Steam Gen. & Dist.	43,009	61,000
Plant & Instrument Air	525	525
Demineralized Water	3,188	4,391
Fuel Gas & N_2	380	380
BFW & condensate	3,189	4,391
Ammonia Disposal	789	789
Fly Ash Collection & Fuel Gas Trm.	16,485	16,485
Stacks & Chimney	855	855
Dust Control	1,050	1,050
TOTAL	$115,815 M	$130,841 M
OFFSITES		
Site Development	$ 8,176 M	$ 8,176 M
Coal & Fly Ash Conveying	5,744	5,744
Electrical System	16,506	16,560
Flares	2,483	2,483
Buildings	4,438	4,438
Fire Water	2,147	2,147
Mud Water	25	25
Fuel Oil	481	481
Cooling Water	2,665	2,665
Clarified Water	834	1,150
Plant & Potable Water	1,101	1,101
Loading & Unloading	529	529
Holding Pond	1,420	1,420
Proc. Effluent Treat	8,750	8,750
Tankage	1,796	4,428
Sulfur Storage	734	734
TOTAL	$ 57,829 M	$ 60,831 M

OPERATING COST SUMMARY
FIRST FULL YEAR OPERATION - M$/YR

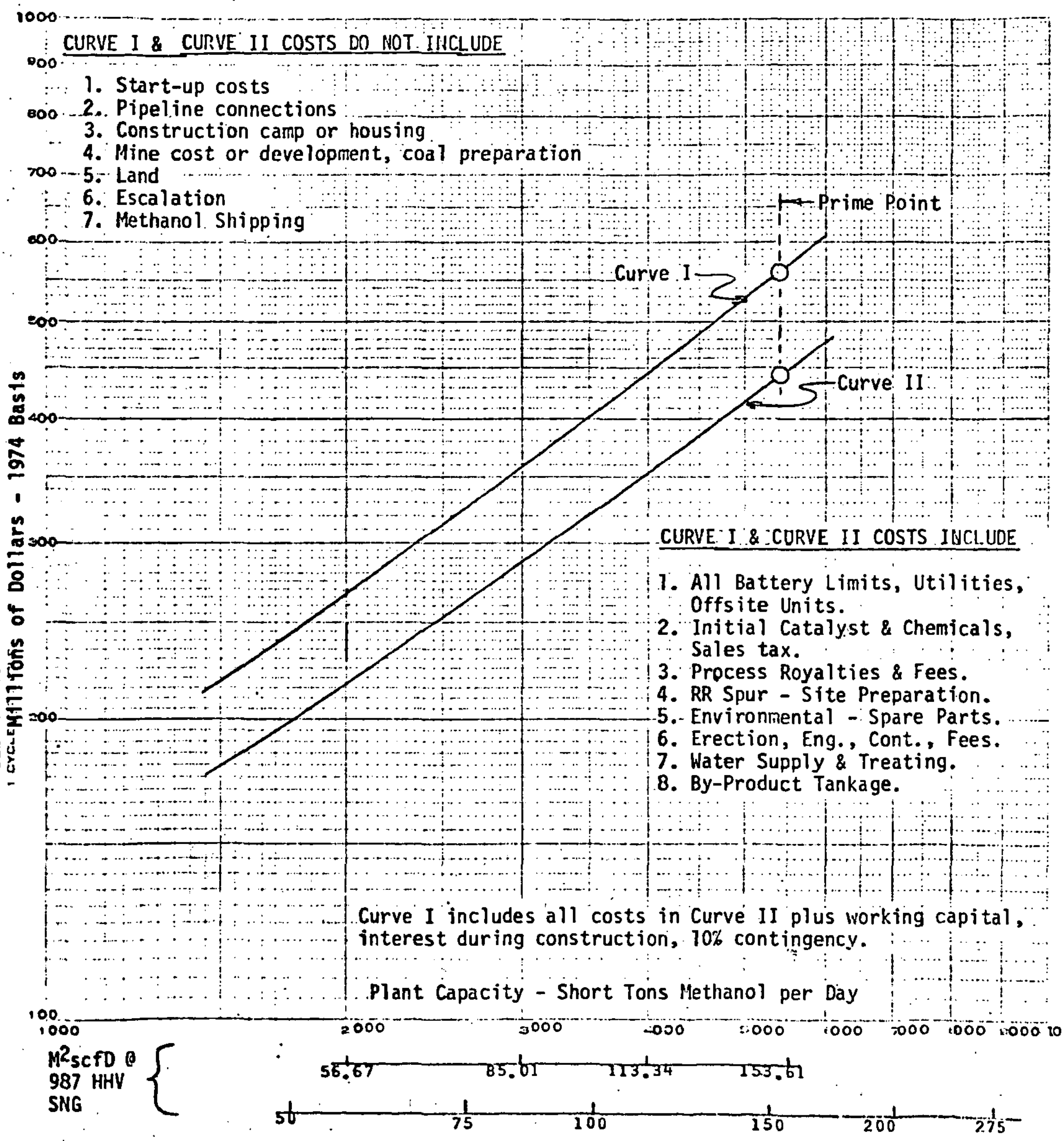
		SNG ONLY	SNG/MeOH
Coal Supply		49,425(1)	54,733(2)
Catalyst & Chemicals		3,366	4,936
Wages & Salaries		7,976	8,360
G&A @ 25%		1,994	2,090
Maintenance Materials		4,830	5,062
Supplies		6,370	6,400
Ash Disposal		500	500
Taxes & Insurance		5,880	6,618
Water Supply		415	501
		80,756	89,200
BY-PRODUCT CREDITS			
Sulfur	78,110 T @ $20/T	1,562	1,562
Crude Phenols	41,610 T @ $50/T	2,081	2,081
Naphtha	56,794 T @ $67/T ($9/bbl)	3,805	3,805
Tars	339,085 T @ $30/T	10,173	10,173
Fuel Oil	112,347 T @ $67/T ($9/bbl)	7,527	7,527
Ammonia	65,700 T @ $85.7/T	5,629	5,629
		30,777	30,777
NET		49,979	58,461

NOTES:

1. 164.751 M^4Btu/Y @ $.30/$M^2$Btu
2. 182.444 M^4Btu/Y @ $.30/$M^2$Btu

COST-SIZE CURVE

CO-PRODUCT SNG/METHYL FUEL - VIA COAL GASIFICATION - LURGI & ICI
Buffalo, Wyoming Coal
(Scale up factor = 0.7169)



G.D.McK.
8-26-74

Exhibit 8

ECONOMICS - EQUAL PRICE/BTU BASIS

	REQUIRED SALES PRICE ($/MMBtu) 25-Year Average	
	SNG PRODUCTION	SNG/MeOH CO-PRODUCTION
30¢/M^2Btu Coal Feed	1.94	2.12
60¢/M^2Btu Coal Feed	2.52	2.73
90¢/M^2Btu Coal Feed	3.09	3.34

SENSITIVITY FACTORS

I. 10% Capital Investment Increment - SALES PRICE INCREMENT

.16

II. 10% Yearly Operating Cost Increment - SALES PRICE INCREMENT

.05

SNG SALES PRICE AT VARIOUS MeOH SALES PRICES

ASSUMED MeOH SALES PRICE		MINIMUM REQUIRED SNG SALE PRICE		
		30¢/M^{2}Btu Coal Feed	60¢/M^{2}Btu Coal Feed	90¢/M^{2}Btu Coal Feed
¢/Gallon	$/MMBtu		$/MMBtu	
16.2	2.50	1.85*	2.89	3.92
19.4	3.00	1.51	2.54*	3.58
22.7	3.50	1.16	2.19	3.23*
25.9	4.00	0.81	1.84	2.88
29.2	4.50	0.46	1.49	2.53
32.4	5.00	0.11	1.15	2.18
35.6	5.50	Negative	0.80	1.83
38.9	6.00	Negative	0.45	1.48
42.1	6.50	Negative	0.10	1.13
45.4	7.00	Negative	Negative	0.79
48.6	7.50	Negative	Negative	0.44
51.8	8.00	Negative	Negative	0.09
55.1	8.50	Negative	Negative	Negative
58.3	9.00	Negative	Negative	Negative
61.6	9.50	Negative	Negative	Negative
64.8	10.00	Negative	Negative	Negative

*Range where co-produced SNG sales price falls below sales price of SNG produced alone.

MINIMUM REQUIRED SNG PRICE

AT VARIOUS MeOH PRICES

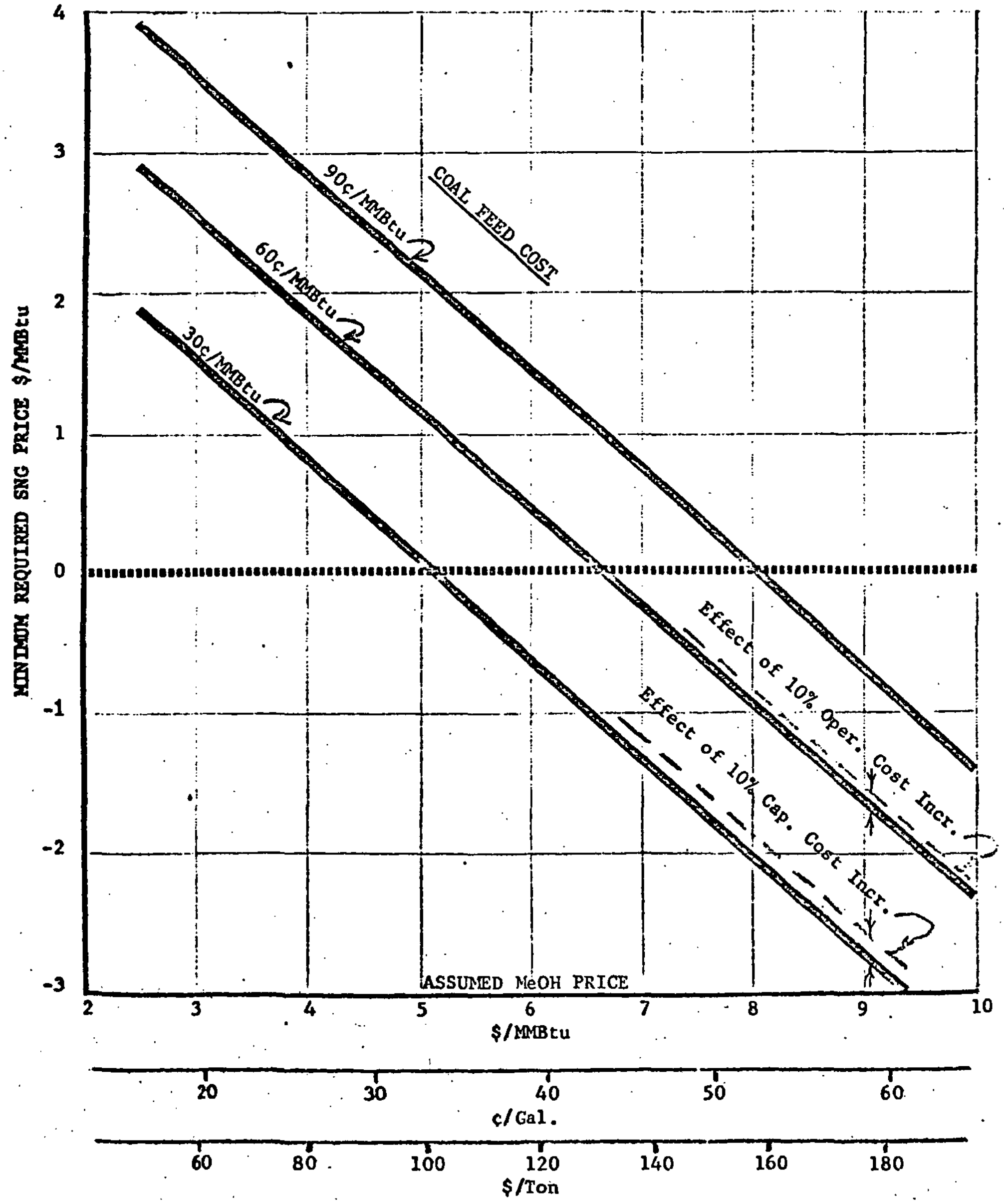


Exhibit 12

UTILITY ENERGY REQUIREMENTS

REPLACEABLE BY CLEAN LIQUID FUELS (METHANOL, NGL)

User	Equipment	Gas MMcf/Day	Methanol Tons/Day
Texas and Louisiana electric utilities	Boilers not requiring conversion	115	5,900
	Boilers requiring conversion	3,450	177,000
	Gas turbines in Texas and Louisiana	44	2,260
Transco customers	Public Service Electric Company's gas turbines (estimate)	55	2,800
	Consolidated Edison Company's gas turbines (1973)	52	2,660
Transco pipeline	Compressors @ 1 trillion CF/yr. delivery	123	6,300

CAS
7/26/74

Exhibit 13

TOTAL U. S. PEAKING FUEL REQUIREMENT

ELECTRIC GENERATING UTILITY INDUSTRY

GAS TURBINES & INTERNAL COMBUSTION ENGINES

Type of Fuel	Fuel Consumption April 1974 (FPC)	Methanol Equivalent
Gas	624,500 Mcf/D	32,000 T/D
Fuel Oil (Distillate)	210,540 Bbls/D	62,800 T/D